U.S. DEPARTMENT OF COMMERCE
National Technical Information Servi

PB-270 093

Inspection Manual for the Enforcement of New Source Performance Standards: Fluid Catalytic Cracking Regenerators

Pacific Environmental Services, Inc, Santa Monica, Calif

Prepared for

Environmental Protection Agency, Washington, D C Div of Stationary Source Enforcement

Oct 76

PB 270 093

EPA 340/1-77-006
APRIL 1977

Stationary Source Enforcement Series

INSPECTION MANUAL FOR ENFORCEMENT OF NEW SOURCE PERFORMANCE STANDARDS

CATALYTIC CRACKING REGENERATORS

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Enforcement
Office of General Enforcement
Washington, D.C. 20460

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE

TECHNICAL REPORT DATA

EPA 340/1-77-006	
Inspection Manual for the Enforcement of New Source Performance Standards: Fluid Catalytic Cracking Regenerators	REPORT DATE October, 1976
AUTHOR(S)	
PERFORMING ORGANIZATION NAME AND ADDRESS Pacific Environmental Services, Inc. 1930 14th Street Santa Monica, California 90404	PROGRAM ELEMENT NO CONTRACT/GRANT NO 68-01-3156, T.O. #19
SPONSORING AGENCY NAME AND ADDRESS U.S. Environmental Protection Agency Division of Stationary Source Enforcement Washington, D.C.	TYPE OF REPORT AND PERIOD COVERED SPONSORING AGENCY CODE /48/83
SUPPLEMENTARY NOTES	

ABSTRACT

The purpose of this document is to assist air pollution agencies in the enforcement of Federal new source performance standards (NSPS) for fluid catalytic cracking (FCC) regenerators. The standards restrict the visible (opacity), particulate, and carbon monoxide emissions from FCC regenerators whose construction or modification commenced on or after June 11, 1973.

This manual outlines the various NSPS regulations which currently apply to an FCC unit, and describes the different types of FCC operations the field inspector must be prepared to examine. This manual also provides an on-site inspection procedure and information checklist which will supply an agency with the information needed to determine compliance with NSPS regulations. A short summarization of the official EPA source test methods is included to enable the inspector to observe performance testing and ensure that proper procedures are used.

KEY WORDS AND DOCUMENT ANALYSIS

DESCRIPTORS	IDENTIFIERS/OPEN ENDED TERMS	COSATI Field/Group
Catalytic Cracking Regeneration Standards	New Source Performance Standards FCC - Fluid Catalytic Cracking Inspection Procedures	1308/0701 1407 1407
DISTRIBUTION STATEMENT Release Unlimited	SECURITY CLASS (This Report) Unclassified SECURITY CLASS (This Page) Unclassified	NO. OF PAGES 61 PRICE PC A04 MF A01

EPA Form 2220-1 (9-73)

INSPECTION MANUAL FOR THE ENFORCEMENT OF NEW SOURCE PERFORMANCE STANDARDS: FLUID CATALYTIC CRACKING REGENERATORS

Contract No. 68-01-3156
Task Order No. 19

EPA Project Officer
Mark Antell

UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY
Division of Stationary Source Enforcement
Washington, D.C.

This report was furnished to the United States Environmental Protection Agency by the Ben Holt Co., Pasadena, California, in fulfillment of Contract No. 68-02-1090, and by Pacific Environmental Services, Inc., Santa Monica, California, in fulfillment of Contract 68-01-3156. The contents of this report are reproduced herein as received from the contractor. The opinions, findings, and conclusions expressed are those of the author and not necessarily those of the Environmental Protection Agency.

TABLE OF CONTENTS

		Page
LIST OF FIGURES		vi
1.0	INTRODUCTION	1-1
2.0	STATE IMPLEMENTATION PLANS (SIP) AND NEW SOURCE PERFORMANCE STANDARDS (NSPS)	2-1
2.1	Existing Sources - SIP	2-1
2.1.1	Summary of Typical Emission Limitation	2-1
2.1.1.1	Particulate Matter	2-1
2.1.1.2	Carbon Monoxide	2-2
2.2	Summary of New Source Performance Standards	2-3
2.2.1	Emission Standards	2-3
2.2.1.1	Particulate Matter	2-3
2.2.1.2	Opacity	2-4
2.2.1.3	Carbon Monoxide	2-5
2.2.2	Performance Testing	2-5
2.2.2.1	Initial Performance Test	2-5
2.2.2.2	Subsequent Performance Tests	2-6
2.2.3	Monitoring Equipment	2-6
2.2.4	Recordkeeping and Reporting	2-6
2.2.4.1	Notifications Regarding Construction, Reconstruction and Modifications	2-6
2.2.4.2	Notifications Regarding Initial Startup	2-7
2.2.4.3	Records Regarding Startup, Shutdown, and Malfunction	2-7
2.2.4.4	Records Regarding Performance Testing	2-7
2.2.4.5	Quarterly Reports	2-8
2.2.4.6	Notification of Monitoring Commencement	2-8
2.2.4.7	Daily Recording	2-8

TABLE OF CONTENTS (continued)

		Page
	2.3 Applicability of Standards	2-8
	2.3.1 Particulate Matter Emission Standard	2-9
	2.3.2 Opacity Standard	2-10
	2.3.3 CO Standard	2-10
3.0	PROCESS DESCRIPTION, ATMOSPHERIC EMISSIONS AND EMISSION CONTROL METHODS	3-1
	3.1 Process Description	3-1
	3.2 Atmospheric Emissions	3-4
	3.3 Emission Control Methods	3-6
4.0	PROCESS AND CONTROL DEVICE INSTRUMENTATION	4-1
	4.1 Process Instrumentation	4-1
	4.2 Control Device Instrumentation	4-1
5.0	STARTUP/MALFUNCTIONS/SHUTDOWN	5-1
	5.1 Startup	5-1
	5.2 Malfunction	5-1
	5.3 Shutdown	5-2
6.0	INSPECTION PROCEDURES	6-1
	6.1 Conduct of Inspection	6-1
	6.1.1 Formal Procedure	6-1
	6.1.2 Overall Inspection Process	6-2
	6.1.3 Safety Equipment and Procedures	6-3
	6.1.4 Frequency of Inspections	6-4
	6.2 Inspection Checklist	6-4
	6.3 Inspection Follow-up Procedures	6-10
7.0	PERFORMANCE TEST	7-1
	7.1 Process Operating Conditions	7-1
	7.2 Process Observations	7-2

TABLE OF CONTENTS (continued)

		Page
7.3	Emission Test Observations	7-3
7.3.1	Traversing (EPA Method No. 1)	7-3
7.3.2	Stack or Duct Gas Velocity Determination (EPA Method No. 2)	7-3
7.3.3	Gas Analysis (EPA Method No. 3)	7-5
7.3.4	Moisture (EPA Method No. 4)	7-5
7.3.5	Particulate Matter (EPA Method No. 5)	7-6
7.3.6	Carbon Monoxide (EPA Method No. 10)	7-8
7.3.7	Emission Monitoring	7-8

APPENDICES

Appendix 1 New Source Performance Standards for Fluid Catalytic Cracking Regenerators

Appendix 2 Proposed Revision to the Opacity Standard for New Fluid Catalytic Cracking Regenerators

Appendix 3 Estimation of the Exit Gas Volume (Q_{sc}) leaving the Fluid Catalytic Cracking Unit Regenerator

LIST OF FIGURES

Figure		Page
3.1	Fluid Catalytic Cracking Units	3-2
3.2	CO Boiler and Precipitator	3-6

1.0 INTRODUCTION

Pursuant to Section 111 of the Clean Air Act, (42 USC 1857 et seq.) the Administrator of the Environmental Protection Agency (EPA) promulgated particulate, carbon monoxide, and opacity standards for performance of new and modified Fluid Catalytic Cracking Regenerators. These proposed standards were issued in the Federal Register of June 11, 1973, and final standards (40 CFR 60.102, 40 CFR 60.103) became effective on February 26, 1974. The standards apply to all sources whose construction or modification commenced after June 11, 1973.

Enforcement of these standards may be delegated by the EPA to individual state agencies for all sources except those owned by the U.S. Government. Each state must first, however, develop a program of inspection procedures for verifying compliance with the standards, and EPA must approve the program.

The primary purpose of this document is to provide guidelines for the appropriate enforcement agency in the development of inspection programs for Fluid Catalytic Cracking Regenerators which are covered by New Source Performance Standards (NSPS). A large portion of the material presented, however, discusses the catalytic cracking process in general and may prove useful in improving procedures used to inspect existing regenerators. Included are sections which explain the process, the regulations, control techniques and the responsibilities of the enforcement agency personnel.

2.0 STATE IMPLEMENTATION PLANS (SIP) AND NEW SOURCE PERFORMANCE STANDARDS (NSPS)

The following sections 2.1 and 2.2 describe the various SIP requirements and the NSPS as related to Catalytic Cracking Regenerators.

2.1 EXISTING SOURCES - SIP

An analysis of rules and regulations of Final State Implementation Plans[1] shows regulations for particulate and CO emissions, applicable to existing Catalytic Cracking Regenerators.

2.1.1 Summary of Typical Emission Limitation

2.1.1.1 Particulate Matter

A number of SIP regulations for various states exist related to particulate emissions. Some of the regulations apply to all stationary sources including refineries, while others are applicable only to petroleum refining operations. Typical examples of the former regulations (all stationary sources) are:

- Los Angeles APCD - limits emissions of solid particulate matter from any source to a maximum of 30 lbs/hr (Rule 54).
- Illinois - the allowable particulate emission rate shall not exceed 100 lbs (45 kg) per hour as determined by:

  $E = 4.10\ (P)^{0.67}$ for $P \leq 30$ tons/hour

  $E = 55\ (P)^{0.11} - 40$ for $30 < P < 4,000$ tons/hour

  $E = 100.0$ for $P \geq 4,000$ tons/hour

  where E = Allowable Emission Rate in lbs/hour

  and P = Catalyst recycle rate including the amount of fresh catalyst added in tons/hour.

An example of a regulation which specifically applies to particulate emissions from the Catalytic Cracking Regeneration process is included in the SIP for the Commonwealth of Pennsylvania. The regulation states that these sources shall not permit the emission of particulate matter in excess of the rate calculated as follows:

$A = 0.76\ (E)^{0.42}$, where:

A = Allowable emission in lbs/hr

E = Emission index = F x W lbs/hr

F = 40 lbs/ton of liquid feed

W = Production or charging rate in tons of liquid feed per hour.

2.1.1.2 Carbon Monoxide

The various regulations pertaining to CO emissions include some which apply to all stationary sources including refineries, and others which are applicable only to petroleum refining CO emissions. Three typical examples of the former (all stationary sources) follow:

- Los Angeles APCD - limits emission of CO from all stationary sources except I.C. engines to 0.2% by volume.
- Louisiana - no emissions of CO from any installation which will cause ambient air quality standards to exceed 9 ppm (max. 8-hour concentration), 35 ppm (max. 1-hour concentration).
- Maryland - no emission of CO from any installation which, without emission control measures, would discharge CO at 500 pounds per day and at a concentration exceeding 12% by volume, unless burned at 1,300°F (720°C) or more for 0.3 seconds or longer in a direct flame afterburner, or equivalent device.

Examples of state regulations for CO emissions applicable specifically to petroleum refineries (including Catalytic Cracking Regenerators) are:

- Illinois - limit emission of CO to 100 ppm corrected to 50% excess air.

- Oklahoma - emissions reduced by use of complete secondary combustion of waste gas generated. Removal of 93% or more of CO generated will be considered complete secondary combustion.

2.2 SUMMARY OF NEW SOURCE PERFORMANCE STANDARDS

Performance standards for new Fluid Cracking Catalyst Regenerators require that the particulate loading of effluent gases from the regenerator not exceed a specified level, that the opacity of any plume issuing from the regenerator not exceed a specified level and that the concentration of carbon monoxide in the effluent gas not exceed a specified level. The regulations were published in the March 8, 1974 Federal Register (39 FR 9315). Since that time there have been periodic updates. The regulations as of February 27, 1976 appear as Appendix I.

These standards included both the maximum emission limits for the specified pollutants and the standards for monitoring the emissions from the fluid catalytic cracking process.

2.2.1 Emission Standards

Levels of particulate loading, opacity, and carbon monoxide concentration of the effluent gases are outlined in following sections. These levels are not to be exceeded during performance testing.

2.2.1.1 Particulate Matter:

The NSP Standard for particulate loading prohibits the emission from a Fluid Catalytic Cracking Unit in excess of 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burnoff in the catalyst regenerator. The coke burnoff rate shall be determined by the following formula [paragraph 60.106 (a)(4)]:

$$R_c = 0.2982\ Q_{RE}\ (\%CO_2 + \%CO) + 2.088\ Q_{RA} - 0.0994\ Q_{RE}\ (\frac{\%CO}{2} + CO_2 + \%O_2)$$

for Metric Units, or

$$R_c = 0.0186\ Q_{RE}\ (\%CO_2 + \%CO) + 0.1303\ Q_{RA} - 0.0062\ Q_{RE}\ (\frac{\%CO}{2} + \%CO_2 + \%O_2)$$

for English Units, where:

R_c = Coke burn-off rate, kg/hr (English units: lb/hr)

0.2982 = Metric units material balance factor divided by 100, kg-min/hr-cubic m

0.0186 = English units material balance factor divided by 100, lb-min/hr-cubic m

Q_{RE} = Fluid catalytic cracking unit catalyst regenerator exhaust gas flow rate before entering the emission control system, as determined by Method 2, dscm/min (English units: dscf/min)

$\%CO_2$ = Percent carbon dioxide by volume, dry basis, as determined by Method 3

%CO = Percent carbon monoxide by volume, dry basis, as determined by Method 3

$\%O_2$ = Percent oxygen by volume, dry basis, as determined by Method 3

0.088 = Metric units material balance factor divided by 100, kg-min/hr-cubic m

0.1303 = English units material balance factor divided by 100, lb-min/hr-cubic ft

Q_{RA} = Air rate to fluid catalytic cracking unit catalyst regenerator, as determined from fluid catalytic cracking unit control room instrumentation, dscm/min (English units: dscf/min)

0.0994 = Metric units material balance factor divided by 100, kg-min/hr-cubic m

0.0062 = English units material balance factor divided by 100, lb-min/hr-cubic ft

In those instances in which auxiliary liquid or solid fossil fuels are burned in the fluid catalytic cracking unit incinerator-waste heat boiler, particular matter in excess of that permitted above may be emitted to the atmosphere, except that the incremental rate of particulate emissions shall not exceed 0.18 g/million cal (0.10 lb/million BTU) of heat input attributable to such liquid or solid fuel.

Particulate matter, for the purposes of this regulation, is defined as that collected in the front half (nozzle, probe, and filter) of the Method 5 train. Condensible organic matter is defined as that collected in the back half (impingers) of the train.

2.2.1.2 Opacity

The NSP standard states that gases exhibiting thirty (30) percent opacity or greater shall not be emitted from a Fluid Catalytic Cracking Regenerator, except for three minutes in any one hour. Where the presence of recombined water is the only reason for this failure to meet the requirements of this standard, such failure shall not be a violation of the standard.

New proposed NSP Standards were presented in the Federal Register, Volume 41, No. 169 - Monday, August 30, 1976 (see Appendix B). The proposed revision would change the opacity standard from thirty (30) percent, except for three minutes in any one hour, to twenty-five (25) percent, except for two six-minute average opacity readings in any one hour.

A continuous monitoring system is required for the measurement of the opacity of emissions discharged into the atmosphere from the fluid catalytic cracking unit catalyst regenerator. The continuous monitoring system shall be spanned at 60, 70, or 80 percent opacity.

2.2.1.3 Carbon Monoxide

The NSP Standard for carbon monoxide is 0.050% by volume on a dry basis (500 parts per million, or 570 milligrams per normal cubic meter).

2.2.2 Performance Testing

Demonstration that the standards are being met is accomplished only by performance testing. The owner or operator of a new or modified Catalytic Cracking Regenerator is required to conduct performance tests within a specified period after startup and thereafter from time to time as may be specified by the EPA.

2.2.2.1 Initial Performance Test

The initial test of performance of a new facility must be conducted within 60 days after the facility is first operated at its maximum intended rate of operation, but not later than 180 days after initial start-up of such facility. Thirty days must be allowed for prior notice to the EPA, to allow the Agency to designate an observer to witness the test.

Each performance must be conducted in accordance with the instructions set forth in the regulations (Appendix I), which are discussed in more detail in Section 7 of this Manual. Necessary modifications in the details of the test methods may be made, if approved in advance by the EPA. A written report of the test must be furnished to the EPA.

2.2.2.2 Subsequent Performance Tests

Subsequent to the initial test, further performance tests may be required from time to time at the discretion of EPA. Alternatively, the Agency may decide to conduct performance tests. For this purpose the owner or operator is required to provide testing facilities, including necessary utilities, sampling ports, safe sampling platforms, and safe access to the sampling platform.

Performance testing subsequent to the initial test is most likely to be required when records indicate a relatively high frequency of occurrence of emission levels near, at, or above the NSPS levels.

2.2.3 Monitoring Equipment

The NSP Standards (40 CFR 60.105) require that the owner or operator of a new or modified Catalytic Cracking Regenerator will install, calibrate, maintain and operate monitoring instruments for the unit's effluent gases. A photoelectric or other type smoke detector and recorder will continuously monitor and record the opacity of the effluent gases discharged into the atmosphere from the unit.

2.2.4 Recordkeeping and Reporting

The owner or operator of any Catalytic Cracking Regenerator is required to maintain certain records, to furnish certain reports and to notify EPA of certain plans and occurrences, as listed below:

2.2.4.1 Notifications Regarding Construction, Reconstruction and Modifications

The owner or operator is required to notify EPA of the date construction of an affected facility is commenced no later than 30 days after such date. A notification is also required for any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies. This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and

proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change.

3.2.4.2 Notifications Regarding Initial Startup

The owner or operator is required to notify EPA of the anticipated date of initial startup of the facility not more than 60 days nor less than 30 days in advance of the anticipated date. He is also required to notify EPA of the date of actual occurrence of initial startup within 15 days after that date. In this connection, "startup" refers to the operation of the facility for any purpose.

3.2.4.3 Records Regarding Startup, Shutdown, and Malfunction

The owner or operator is required to record the occurrence and duration of any startup, shutdown, or malfunction in operation of the Catalytic Cracking Regenerator and to retain the record for at least two years thereafter.

The record should also include the nature and cause of any malfunction, together with a notation as to corrective action and any measures undertaken to prevent recurrence of the malfunction.

In this connection, "startup" refers to a renewed operation of the facility for any purpose; and "malfunction" is defined as any sudden, unavoidable failure of air pollution control equipment or of the Regenerator itself to operate in a normal manner. Preventable failures, such as those which may have been caused by poor maintenance or careless operation, or by equipment breakdown due to such causes, are not included in this definition.

3.2.4.4 Records Regarding Performance Testing

The owner or operator is required to make available to the EPA, in order to facilitate conduct of performance tests by the Agency, any records necessary to determine whether performance of the Regenerator is representative performance at the time of the test. Production rate and hours of operation for any Fluid Catalytic Cracking Unit Regenerator shall be recorded daily. A file of all measurements required by CO and particulate emissions regulations shall be maintained by the owner or operator. Appropriate measurements shall be reduced if necessary to the units of the applicable standard daily, and summarized monthly. The record of any such measurement(s) and summary shall be retained for at least two years following the date of such measurements and summaries. These records should also be made available during inspections of the facility.

2.2.4.6 Quarterly Reports

Quarterly reports are to be filed on the fifteenth day following the end of each calendar quarter. These reports must include the records of excessive emissions during the calendar quarter in terms of date, time of commencement, and time of completion for each period of excessive emissions, as evidenced by records of monitoring equipment or other observations. The quarterly reports must also include the records of startup, shutdown, and malfunction during the calendar quarter, with details as to the causes of malfunctions and corrective measures applied.

2.2.4.6 Notification of Monitoring Commencement

A notification is required of the date upon which demonstration of the continuous monitoring system performance commences.

2.2.4.7 Daily Recording

The average coke burn-off rate (thousands of kilogram/hour) and hours of operation for any Fluid Catalytic Cracking Unit catalyst regenerator shall be recorded daily.

2.3 APPLICABILITY OF STANDARDS

The applicability of the NSP standards includes all new or modified Fluid Catalytic Cracking Regenerator units and all unit incinerator-waste heat boilers. A new or modified source is one on which construction or modification commenced after June 11, 1973, subject to the following definitions (40 CFR 60.2):

> "Modification" means any physical change in, or change in the methods of operation of, an affected facility which increases the amount of any air pollutant (to which a standard applies) emitted by such facility or which results in the emission of any air pollutant (to which a standard applies) not previously emitted, except that:
>
> (a) Routine maintenance, repair and replacement shall not be considered physical changes, and
>
> (b) The following shall not be considered in themselves to be a change in the method of operation:

(i) An increase in the production rate, if such increase does not exceed the operating design capacity of the affected facility;

(ii) An increase in hours of operation;

(iii) Use of an alternative fuel or raw material if, prior to June 11, 1973, the affected facility was designed to accommodate such alternative use.

(iv) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system determined to be less environmentally beneficial.

(v) The relocation or change in ownership of an existing facility.

"Commenced" means that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a binding agreement or contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

2.3.1 Particulate Matter Emission Standard

The performance standard for emission of particulate matter, applicable to new Regenerators, is 1.0 kg /1,000 kg (1.0 lb/1,000 lb) of coke burn-off; no owner or operator is permitted to cause discharge of effluent gases whose particulate emission exceeds this value. However, the actual particulate loading of the effluent gases will not be known during routine operation of the facility. A determination as to whether the facility is or is not in compliance with this regulation may be based only on the results of performance tests conducted in the manner prescribed in Section 60.106 (see Appendix I).

Paragraph 60.106(a) (Appendix I) specifies that EPA Method 5 be used for determining the concentration of particulate matter and the moisture content. For Method 5, the sampling time shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved when process variables or other factors preclude sampling for at least 60 minutes.

When the production rate is nonuniform as will frequently be the case, it may be difficult to determine what would be the normal maximum production rate referred to during the period alloted for the test. The normal maximum production rate will be determined in this case by the unit operator. However, the operator will have to show the reasonableness of this rate based on design capacities of the unit including fresh feed rate, catalyst recirculation rate and coke burnoff rate.

2.3.2 Opacity Standard

The performance standard is 30% opacity, not to be exceeded for more than three minutes of any one hour. Where the presence of uncombined water is the only reason for failure to meet the requirements, such failure would not be considered a violation. For determining initial compliance, this observation can only be made during an established performance test. Following the performance test, opacity observations can be made from time to time to determine if the unit appears to be maintaining its compliance status.

Revisions to this rule have been proposed but not promulgated and appear as Appendix 2.

2.3.3 Carbon Monoxide Standard

The standard was described in Section 2.2.1.3 (0.050% by volume). For the purpose of determining compliance with this performance standard, the integrated sample technique of Method 10 shall be used. The sample shall be extracted at a rate proportional to the gas velocity at a sampling port near the centroid of the duct. The sampling time shall not be less than 60 minutes.

REFERENCES FOR CHAPTER 2

1. Duncan, L.J., "Analysis of Final State Implementation Plans - Rules and Regulations," Environmental Protection Agency, Office of Air Programs, Research Triangle Park, N.C., Publication Number AP10 - 1334, July, 1972.

3.0 PROCESS DESCRIPTION, ATMOSPHERIC EMISSIONS AND EMISSION CONTROL METHODS

3.1 PROCESS DESCRIPTION

The principal use of the fluid catalytic cracking (FCC) process is to convert gas oil feed stocks to high quality gasoline. Heavier liquid products and gas are also produced, along with coke which is deposited on the catalyst. In order to reuse the catalyst the coke is removed by burning.

A flowsheet for a typical FCC unit is shown in Figure 3.1. This specific unit employs a riser reactor, a process variation that has become popular in recent years. Variations in equipment arrangements and process details are common, but the major elements are similar and the regenerator effluent control problems are the same.

Powdered catalyst, both regenerated and as addition (make-up) with the appearance of fine sand, is fluidized in combination with vaporized feed and steam added to the lower part of the riser reactor. The mixed feed, steam, and catalyst reacts and flows upward into the cyclone vessel where the catalyst is disengaged from the vapor mixture. Multistage cyclones (usually two), located within the cyclone vessel, are used to remove catalyst from the reactor effluent vapors. The reactor effluent (catalytically cracked gas oils) then flows to a section of the refinery devoted to product recovery and fractionation.

The catalyst captured in the cyclone vessel is laden with coke (carbon) which will seriously affect the activity level of the catalyst unless it is removed. In order to recover this "spent" catalyst, the fluid catalytic cracking unit has a regeneration process. The captured spent catalyst from the cyclone vessel is brought into contact with steam in the stripper to absorb hydrocarbon. The stripped spent catalyst then flows to the regenerator. In the regenerator, compressed air is fed to the chamber through the bottom of the vessel. The air contacts the hot catalyst at approximately 593°C (1,100°F) causing combustion of the coke. In the standard regeneration process, neither the structure of the vessel nor the catalyst used is hearty enough to withstand a high enough temperature to ensure complete combustion of the carbon to carbon dioxide (CO_2). As a consequence, the gases generated in the vessel are characterized by large quantities of carbon monoxide (CO) and the captured catalyst leaving the vessel retains a small amount of the coke causing a deterioration of the catalyst activity level.

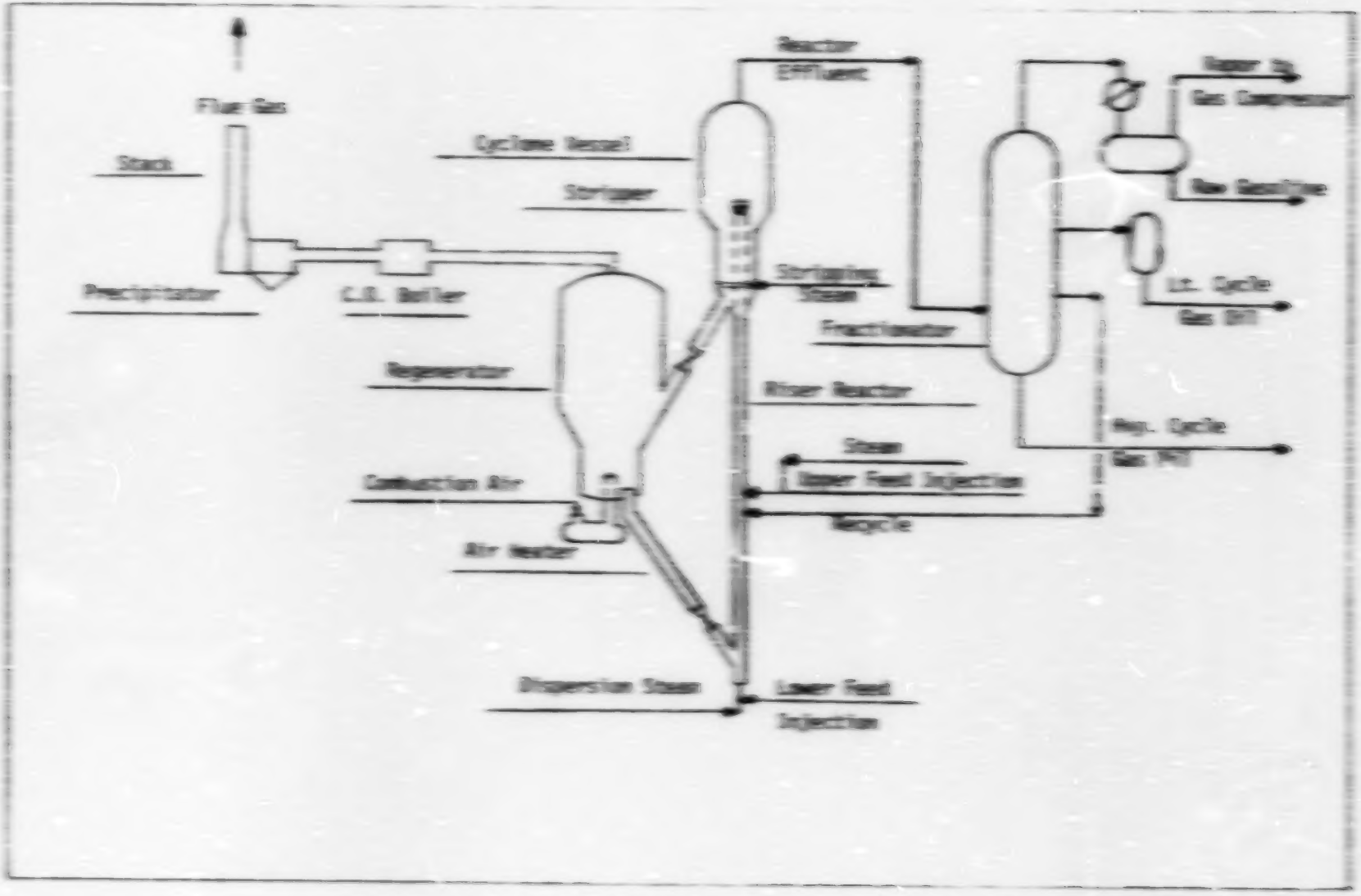

Figure 3.1 FLUID CATALYTIC CRACKING UNIT

The regenerated catalyst and the burned off coke (as CO and CO_2) along with other combustion contaminants rise to the top of the regenerator vessel where multiple stages of internal cyclones separate all but a small amount of the catalyst fines from the flue gas. In some units additional external (tertiary) cyclones are also used. Completion of the combustion of CO to CO_2 in the flue gas can be performed downstream of the regeneration in a CO (often termed waste heat) boiler. In the CO boiler, auxiliary fuel is used to maintain combustion and stabilize the operation, and useful heat is recovered in the form of steam. The flue gas from the CO boiler is passed through an electrostatic precipitator for removal of the remaining catalyst fines and leaves the unit through the stack. In some units the precipitator is located upstream of the CO boiler.

A turbine is sometimes inserted ahead of the CO boiler to recover power available from the pressure drop which exists between the regenerator vessel exit and the final exhaust stack. In such cases an additional stage of cyclones, exterior to the regenerator, is used to remove catalyst fine that would otherwise damage the turbine. The external cyclones do not effect complete particulate collection so a precipitator is still required for final particulate control.

One advancement in the FCC regeneration process termed hot regeneration has been developed by Universal Oil Products (UOP). The process allows for complete combustion of carbon monoxide to carbon dioxide within the regenerator chamber and can be applied to both new and existing units. Hot regeneration requires an operating temperature of about 732°C (1,350°F) which means existing FCC units will require structural modifications in the form of a refractory lining of the interior of the regenerator vessel in order to withstand the higher temperature. Hot regeneration also requires the use of a special catalyst developed specifically for the process which is durable enough to withstand the temperature without losing activity levels.

A more recent improvement of the standard FCC operation is a process which accomplishes complete combustion in the regenerator of existing units without requiring a higher operating temperature. The process, developed by American Oil Company (AMOCO), is called Ultracat. Ultracat is the result of a detailed study of the total FCC operation and involves the application of design modifications and special control techniques to both the reactor and regenerator. Ultracat reactor operations improve conversion efficiency to gasoline and reduce the amount of carbon deposited on the catalyst. This allows an existing regenerator to accomplish complete combustion without necessitating higher operating temperatures and the associated major structural modifications.

3.0 ATMOSPHERIC EMISSIONS

The most significant source of atmospheric emissions from a FCC regenerator is the exhaust stack. In addition to the large quantities of carbon monoxide and particulate emissions discussed earlier, significant quantities of sulfur oxides (generated during combustion due to the large sulfur contents which characterize this form of coke), nitrogen oxides and hydrocarbons are emitted. Smaller amounts of ammonia, aldehydes and cyanide are also present. The handling of catalyst both into the system and out of the collection equipment can pose a fugitive dust problem. New Source Performance Standards (NSPS) have been established for carbon monoxide and particulates.

As was discussed in the previous section, the amounts of the various pollutants entering the control devices are influenced by the design and operating factors in the FCC unit. For instance, the amounts of sulfur oxides increases with feed rate, sulfur content of the feed, and conversion level. The amount of carbon monoxide increases with the amount of coke produced, which increases with feed rate and conversion level and is also influenced by catalyst type. Particulate loading varies with the type of catalyst and increases with catalyst circulation rate and the rate of regeneration air. These rates are, in turn, a function of the feed rate and conversion level.

Another factor which may affect particulate emissions is the length of time since last turnaround. Turnaround is a standard refinery practice which involves the complete shutdown of the FCC unit for maintenance and catalyst replacement. The practice occurs approximately every two years with the exact time varying greatly between refiners depending on the type of process employed. One of the prime factors which dictates turnaround is a gradual trend toward lower conversion efficiencies of the feedstocks due to decreased catalyst activity. Despite the fact that new catalyst is constantly added to the operation to stimulate high activity levels, with time an unavoidable general aging of the catalyst takes place. In addition to an accumulation of coke deposits on the catalyst caused by the inability of the regenerator to perform at one-hundred percent efficiency, the catalytic binder begins to deteriorate, breaking down the particle and accelerating the formation of fines. Because the efficiency of the internal cyclones is less for the smaller particles, as their numbers increase, fines begin to appear in the recirculated stream and the exhaust stream in higher rates.

Once this combined effect reaches a certain point, a turnaround is performed. Source test reports on FCC units do not record the elapsed time since last turnaround meaning that to date there are no statistical means available to attempt to quantify any correlation between length of time of operation and particulate emission increases.

3.3 EMISSION CONTROL METHODS

Carbon monoxide and particulate emissions are commonly controlled by the devices shown in Figure 3.2. Carbon monoxide is converted to carbon dioxide in the CO boiler and particulates are removed in the electrostatic precipitator. In some units the precipitator is located upstream of the CO boiler.

Flue gas leaves the regenerator and enters the control system through an orifice chamber, used to reduce pressure without creating noise or valve wear. The flue gas, along with the air supplied by a compressor and fuel gas, is then fed to the combustion chamber of the CO boiler. The sensible heat of the flue gas, as well as the heat of combustion of the carbon monoxide and fuel gas, is recovered by producing steam using conventional steam boiler practices. Exit gas from the CO boiler is passed through electrostatic precipitators for removal of particulates and then through the stack for dispersal to the atmosphere.

A two port slide valve is provided ahead of the CO boiler to permit the bypassing of regenerator flue gas in case maintenance or emergency repairs of the boiler are required. The precipitator collection chambers can be multiple units installed in parallel so that a unit can be taken out of service for repair without interrupting operations.

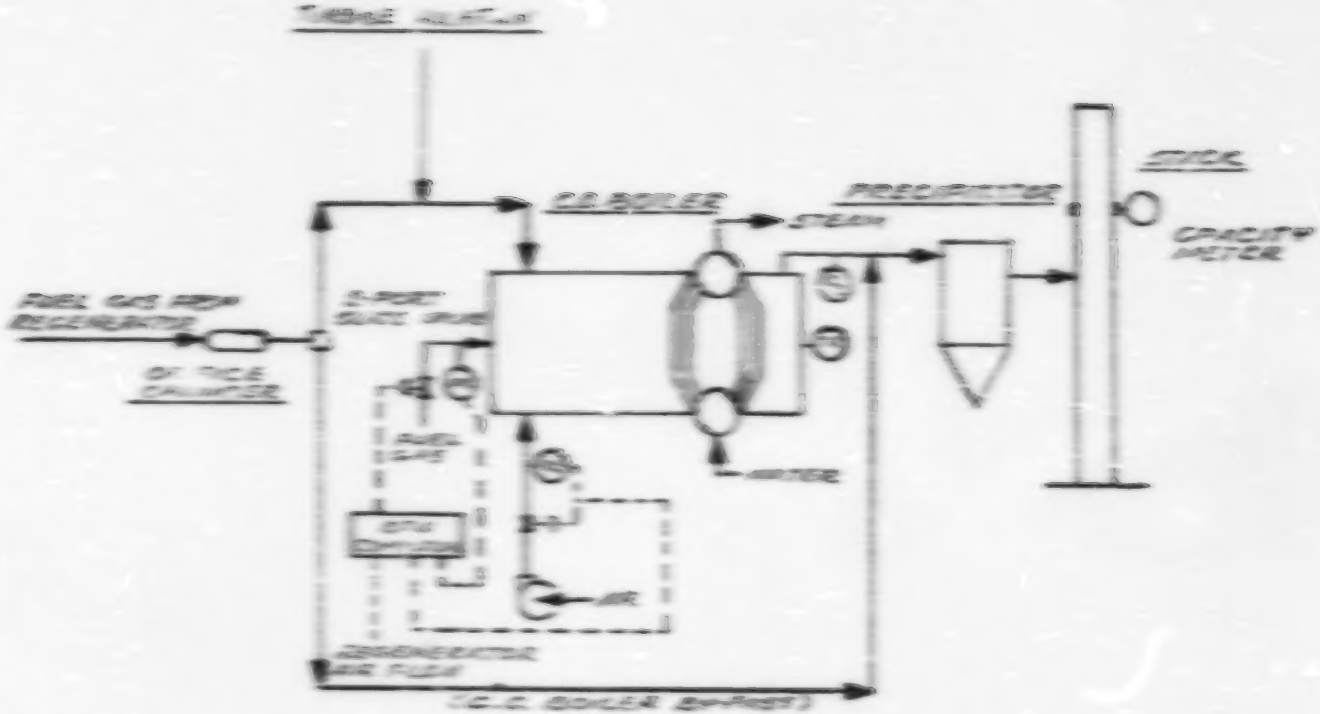

Figure 1.1

C.O. Boiler and Precipitator

4.0 PROCESS AND CONTROL DEVICE INSTRUMENTATION

4.1 PROCESS INSTRUMENTATION

The process instruments of particular importance from the standpoint of NSPS are the hydrocarbon feed flow rate recorder-controller and the regenerator air flow rate recorder-controller. Performance tests are normally to be made while the unit is operating at or above the maximum expected production rate, based on the feed rate. For a given combination of feed rate, feed stock, catalyst and conversion level there is an expected rate of coke formation. The air required for burning this coke is supplied to the regenerator by a compressor under flow rate control and the air rate is directly related to the regenerator flue gas rate. Flue gas rate influences catalyst carryover, gas velocities in the cyclones and precipitator and residence time in the CO boiler. Other instruments measuring variables such as reactor and regenerator temperature and pressure and product gasoline flow rate can be checked against design values to establish that the unit is operating normally.

The NSPS regulation for allowable particulate matter from a regenerator is calculated as a direct percentage of the coke burnoff rate. The control room of a FCC unit does not normally have a continuous readout of the burnoff rate. In isolated cases, control rooms will be tied to a computer (such as an IBDO IBM) and capable of an instantaneous value. The majority of the time, however, it will be necessary to determine the coke burnoff rate by use of the equation discussed in Section 8.2.1.1. The equation solution requires values for five variables: (1) Q_{RE}, the FCC exhaust flow rate; (2) Q_{RA}, the air rate to the FCC regenerator; (3) percent CO_2; (4) percent CO; and (5) percent O_2. Normal process instrumentation will include the air blower rate to the regenerator (Q_{RA}) on a continuous basis; a gas chromatograph readout of the exhaust stack with the percentages of CO_2, CO, and O_2 on a dry basis; the process operating temperature will be on a continuous readout but may not be easy to obtain and document due to the highly confidential nature of this value.

4.2 CONTROL DEVICE INSTRUMENTATION

The NSPS as applied to FCC units requires a continuous moni-

toring system for the measurement of the opacity of emissions. The continuous monitoring system shall be spanned at 60, 70, or 80 percent opacity.

The opacity meters in general use are of the photoelectric type. A light source is mounted on one side of the stack and the beam passes through the flue gas and strikes the photoelectric cell mounted on the opposite side. The signal from the photoelectric cell is continuously recorded.

The reader should be aware of the fact that a revision of the NSPS opacity requirement has been proposed in the Federal Register, Volume 41, No. 169 - Monday, August 30, 1976 (see Appendix B).

While there are no longer NSPS requirements for the monitoring of carbon monoxide from a FCC regenerator, the enforcement agency should be aware of devices capable of quantifying CO emissions. Experts in the catalytic cracking field tend to agree that a relationship can be drawn between the percent combustion accomplished in the regenerator and the temperature and oxygen (O_2) content. However, after checking with sources in both government and industry, it seems apparent that an accurate confirmation of this possibility in the form of equations or a graphic representation (nomograph) is not currently available. A large part of the problem is associated with the lack of a 'typical' set of process operating parameters from which to draw a correlation which can be applied to any unit.

In the conventional FCC operation, the carbon monoxide exiting the regenerator is destroyed in a CO boiler. Instruments have been developed which are suitable for use in continuously monitoring and recording directly the carbon monoxide concentration of a flue gas. At this time, these devices are not considered to be as reliable and trouble-free as the combination of an oxygen meter and temperature recorder. Incinerating carbon monoxide in the presence of excess air for a suitable length of time at a suitable temperature (for instance 0.3 seconds at 1,300°F) has been found to reduce the concentration satisfactorily. Therefore, the combination of an oxygen meter and temperature recorder probe is mounted in the firebox of the CO boiler and the oxygen meter sample is taken from the exit gas duct.

Other control device instrumentation includes combustion controls for the CO boiler, and electrical current and rapper controls for the precipitator. The combustion controls may include a BTU computer, used to match fuel gas flow with CO boiler air and regenerator flue gas rates.

In some precipitators a spark counter is used to measure the rate at which arcing occurs, and the voltage is automatically

controlled to maintain the desired spark rate. A low but definite spark rate is associated with maximum effective corona discharge, and high collection efficiency.

Mechanical rappers are used to dislodge the catalyst fines from the precipitator collector plates. Proper timing and sequencing of rapper operation is needed to meet the current limitation of opacity greater than 30% in any one hour.

Particulate matter has a tendency to collect on the CO boiler tubes reducing the heat transfer and therefore steam generating capabilities. To alleviate this problem, the boiler is "soot blown" to remove this collected material. Soot blowing consists of injecting pressurized air or steam across the tubes which loosens any accumulated carbon and transports it downstream to either an electrostatic precipitator or the exit stack. During soot blowing, it is not uncommon for the maximum opacity limitation to be exceeded. Therefore, it is important to time the blowing cycle so that it can be accomplished within the time limitations of the NSPS opacity regulation.

5.0 STARTUP/MALFUNCTIONS/SHUTDOWN

5.1 STARTUP

It is considered normal for an FCC unit to operate without shutdown for at least two years, so that startups are infrequent. A startup can be expected to take one or two days from a cold start to full operation, with a period of operation at reduced feed rates. Emissions during the startup period should not exceed the standards unless a malfunction occurs. The unit operator is also required by regulation to "use maintenance and operating procedures designed to minimize emissions" during startup, shutdown and malfuction.

5.2 MALFUNCTION

Malfunctions in the reactor and fractionation sections of an FCC unit may lead to shutdowns or operation at reduced feed rates, but do not usually result in increased emissions from the regenerator section.

Regenerator and control device malfunctions that may affect emissions include the following:

- Cyclone damage
- CO boiler failure
- Precipitator wire breakage
- Rapper failure
- High voltage supply failure

Regenerator cyclones are subject to severe erosion by the abrasive catalyst. If the cyclones are sufficiently worn, they fail to separate the catalyst from the flue gas and large amounts of catalyst are carried into the CO boiler and precipitator. Catalyst losses may become so large that the unit must be shut down for economic reasons, but smaller losses can overload the precipitator. The entire FCC unit must be shut down if cyclone repair is required.

CO boilers are very reliable and usually can be expected to operate continuously for the two-year period between turnarounds. A bypass is provided, however, so that the boiler can be taken out of service temporarily for either minor repairs or for periodic

safety inspections. Repairs would include burner replacement, the repairs of feed water pumps and the repair of air blowers. Carbon monoxide standards are exceeded while the boiler is out of service so such periods must be limited.

Discharge electrodes in electrostatic precipitators frequently take the form of wires, weighted at the bottom and hung vertically between collector plates. Breakage of these wires is a common cause of lost efficiency, and broken wires may need replacing every few months.

If the precipitator has several parallel trains, wire replacement can be accomplished by taking one section of the precipitator at a time out of service, so that the unit can continue to function. If the precipitator in question has only one train, the options are fewer. Therefore, electrostatic precipitator installations with more than one train should be encouraged.

If a rapper or its control fails to operate, the corresponding collector plates will become clogged and collection efficiency will suffer. Rapper repairs should not be required more than once or twice between turnarounds.

Interrruption of the high voltage supply stops precipitator operation and particulate removal will cease. High voltage is normally supplied by parallel units serving the corresponding collection sections, so that repairs are usually possible without taking the entire precipitator unit out of service.

5.3 SHUTDOWNS

Shutdowns, or turnarounds, are normally planned well in advance and generally occur about once every two years, although some units have shown the capability of going over six years without a turnaround. All major maintenance is scheduled for these periods and only a serious emergency will justify an unplanned shutdown. Planned shutdowns should not result in exceeding NSPS regulations.

REFERENCE FOR CHAPTER 6

1. Federal Register, Vol. 38, No. 198, October 15, 1973.

6.0 INSPECTION PROCEDURES

An air pollution inspection consists of entering a refinery to determine if the equipment or processes under investigation meet the standard and comply with the rules and regulations of the air pollution control agency. The inspection process also includes a spot check of records maintained by the operator. The Inspection Officer (IO) must observe, in a qualitative manner, the items associated with atmospheric emissions. The condition and type of equipment, and general housekeeping all influence the emission rate. Equipment design is a major factor that must be reviewed at the time the construction permit or operating permit applications are evaluated.

The importance of plant inspection as a field operations activity that provides for the systematic detection and observation of emission sources cannot be overemphasized. The whole process of inspection follows certain rules and guidelines which are discussed briefly in the following sections.

6.1 CONDUCT OF INSPECTION

There are four important components in the conduction of an inspection of a given equipment or process.

- Formal procedure (e.g., use of credentials, ask to see appropriate official)
- Overall inspection process (e.g., review of process and records)
- Safety precautions and procedures
- Frequency of inspection

6.1.1 Formal Procedure

Prior to the actual on site inspection, the IO should investigate any available data on plant operations. In preparation for the inspection the official should obtain the following data:

- Information for each major source (from an air pollution point of view) including process descriptions, and estimated flow rates, flow diagrams, estimates of emissions, applicability of standards, and previous related enforcement actions.

- Plot plans showing disposition of all major units at the facility including the location of the FCC unit.
- Business and ownership data including names of responsible management personnel.

At the time of inspection, the IO must have with him the credentials showing his identity as an official of an air pollution control agency. He should arrange an interview with the management of the refinery. The interview with refinery managers and equipment operators can verify data gathered and clarify any misunderstanding with regard to the information reviewed prior to the inspection.

6.1.2 Overall Inspection Process

Some inspections, especially initial ones, are comprehensive, designed to gather information on all equipment and processes in question at the refinery. Others are conducted for specific purposes such as:

- Obtaining information relating to violations
- Gathering evidence relating to violations
- Checking permit or compliance plan status of equipment
- Investigating complaints
- Following up on a previous inspection
- Obtaining emissions information by source testing

An initial inspection lays the groundwork for evaluating potential emissions of pollutants from the FCC regenerator and for assessing the relative magnitude of pollution control problems requiring correction, reinspection, or further attention.

The initial inspection has two phases: an initial general survey and a physical inspection of the specific equipment and processes. After this inspection is complete, routine surveillance continues. Periodic reinspections are scheduled and occasional special purpose inspections (unscheduled) may be required.

During the initial survey, the inspector examines the possible effects of emissions on property, persons and vegetation adjacent to the source; he may also collect samples or specimens that exhibit possible pollution related damage. Sensory observations (odor detection) are also made.

The NSPS regulations for the FCC Regenerator have been presented in Chapter 2. The specific details are given in Section 2.2, including the various records related to the process which must be maintained. The inspector should also review the records kept by the operator and the readouts available in the control room. The procedure necessary to determine the allowable particulates rate from the coke burnoff rate has already been discussed. The inspection officer can expect to find the air blower rate to the regenerator (Q_{RA}) on a continuous readout in the control room. While Q_{RE} (the exhaust gas flow rate) is not directly available, (see Appendix 3), the percent CO, CO_2, and O_2 on a dry basis leaving the regenerator are read by a gas chromatograph on a continuous basis and available in the control room. This gas chromatograph also reads hydrogen, which is all assumed to leave as water. By calculating the hydrogen readout as water, an estimate can be made of the moisture content. The inspector should be warned that refinery personnel consider many of the operating values associated with an FCC unit to be proprietary in nature and that special care should be given to receiving the necessary clearance for the recording of information.

An additional aid to the IO is the information incorporated in applications to operate the equipment. The permit status of the equipment should be routinely checked to detect any changes in equipment or process that might invalidate an existing permit or conflict with variance conditions.

Similarly, alteration of equipment is frequently detected by discrepancies in the equipment description or by changes noted on engineering applications in the permit file.

6.1.3 Safety Equipment and Procedures

All refineries have standard safety procedures for employees and visitors. These procedures also concern the IO. The IO is accompanied to the unit or units to be inspected by the air pollution representative within the plant or by such other informed refinery personnel as he might indicate.

Personnel protection is necessary in many of the industrial locations that an officer may be required to visit.

The IO should wear a hard safety hat head covering while in a plant. He should wear rubber gloves and goggles when necessary. In the event of fire in the area of inspection, the IO must leave immediately, and remain outside the area until the "All Out" signal is sounded. For safety, the IO should be accompanied by another person and the two individuals should remain together until the job is completed. He must not smoke or carry cigarette lighters which may ignite when dropped within an oil refinery. He should use only approved flashlights in oil refineries.

6.1.4 Frequency of Inspections

Because of the complexity of the petroleum industry and the FCC unit in particular, the unit must be inspected systematically and regularly. The frequency of reinspection is based upon the findings during the initial inspection and the recommendations of the IO and his supervisor. These recommendations obviously depend on whether or not "good" maintenance practices from the pollution standpoint are followed by the operator. Further, the frequency would depend on the overall inspection load of the control agency for the whole district. The reinspections are scheduled so that they can be completed within a month. The number of reinspections assigned per district is based on the estimate that all required inspections can be completed within one year.

The inspection officer may have occasion to inspect the process out of schedule because of complaints or violations. In these cases, he does not make a formal inventory reinspection, but uses the copy of the previous inventory record (equipment list) from his files as a check on status of the permit, compliance, or other situation.

6.2 INSPECTION CHECKLIST

Data necessary for NSPS compliance determination obtained during an inspection can be summarized on forms similar to the one shown on the following pages. These forms also serve as a record of inspection.

A possible problem the Inspection Officer should always be aware of in the data gathering process is confidentiality of information. Many of the FCC operation parameters desired by the IO can be expected to be considered confidential by the source. The IO should inform the concerned party that under the provision of the Clean Air Act he has the right to request whatever information he considers to be necessary for his investigation but that he is bound by law to honor the confidential nature of business information as defined in the Code of Federal Register, Title 40, Chapter 1, pages 36902-36924, appearing Wednesday, September 1, 1976.

During the inspection, the IO should attempt to gain a feel for the refiner's commitment to the use of "good" maintenance procedures. Checking to ensure that proper procedures are being followed can prove difficult for the regenerator vessel itself. Just as operational parameters differ with each unit, the maintenance necessary to keep each unit operating properly also varies. There are, however, several conditions the IO can check to determine whether proper maintenance is being performed on the electrostatic precipitator (ESP) and the opacity monitoring device.

The most common problem associated with an ESP is the loss of the weights which are attached to the end of the electrode. The loose electrode wires then have a tendency to wrap themselves around each other and short out sections of the system. To reduce the frequency of this occurence, the internal sections of the ESP should be visually inspected at least once a month. The IO can check to be sure that this is being done by asking to see the maintenance log.

Opacity meters require a great deal of routine blower filter maintenance in order to operate properly. The operator should keep a log showing the history of the filter maintenance. If this log is not kept or the IO has any other reason to suspect that the meter is operating improperly, he should ask the operator to perform a zero check and a span check. Each of these tests can be performed almost instantaneously. The zero test uses a retroreflector to simulate zero opacity in the stack and indicates if the meter has any zero drift. The span check utilizes a series of optical density setters to simulate specific stack opacities.

INSPECTION CHECK LIST FOR
CATALYTIC CRACKING REGENERATORS

FACILITY IDENTIFICATION

Facility Name _____

Facility Address _____

Mailing Address _____

Telephone Number _____

Date of Last Inspection _____

Responsible Person to Contact _____

Persons Contacted at Plant Site _____

Inspectors _____

Source Code Number _____

OPACITY OBSERVATIONS

Emission Source _____

Average percent equivalent opacity from Method 9 observation _____

Reading ranged from _____ to _____% opacity

Minutes in any one hour of 30%* or greater opacity _____

Compliance status with opacity regulation _____

*This value may change to 20% under the proposed new regulations (see Appendix D).

FLUID CATALYTIC CRACKING UNIT AND REGENERATOR

(A) Input to cracking unit (e.g. gas oil feed stock etc.) _____ Barrel/day

(B) Catalyst recycle rate _____ Tons/min

(C) Catalyst makeup rate _____ Tons/hour

(D) Coke burnoff rate _____ Pounds/hour

(1) In the event that the coke burnoff rate is not directly known, the IO must obtain the following information:

(a) the controlled air rate to the fluid catalytic cracking unit catalyst regenerator _____ dscm/min

(b) volume percent CO on a dry basis leaving the regenerator _____ %

(c) volume percent CO_2 on a dry basis leaving the regenerator _____ %

(d) volume percent O_2 on a dry basis leaving the regenerator _____ %

(e) fluid catalytic cracking unit catalyst regenerator exhaust gas flow rate before entering the emission control system (if known) _____ dscm/min

(E) Hours of operation _____ hours/day

(F) Has a source test been conducted on the unit recently which regulatory agencies are not aware of? If so, the IO should attempt to obtain a copy of this test.

CO BOILER (AFTERBURNER)

(A) Temperature of gas entering CO boiler _____ °C

(B) Flow rate of gas entering CO boiler _____ M^3/second

(C) Combustion temperature in CO boiler _____ °C

(D) Auxiliary fuel(s) used
(1) Heat value of fuel(s) _____
(2) Quantity of fuel(s) used _____

PARTICULATE POLLUTION CONTROL EQUIPMENT

(A) Number of stages of internal cyclones in the regenerator

(B) External Pollution Control Equipment
(1) Cyclone separators, type _____

Evidence of corrosion and wear _____

Estimated collection efficiency _____

Pressure drop _____

Inlet temperature _____

(2) Electrostatic precipitators (ESP), type _____

Evidence of corrosion and wear _____

Voltage measurements and regulation _____

Electrodes broken? _____

Condition of collection plates and tubes _____

Alignment of plates _____

Condition of rapping mechanism _____

Rapper timing _____

Sparking rate _____

(3) Scrubber, type

Evidence of corrosion and wear _____

Pressure drop _____

Effluent disposal system _____

Estimated collection efficiency _____

RECORDS OF OPERATION

Quality of records (circle one) Good Fair Poor

Regulations regarding recordkeeping being followed? (See Section 2.2 regulations)

Opacity _____

Startup, shutdown, and malfunction _____

Performance testing _____

OPERATIONAL ASPECTS

(a) Plant operating within specified limits? Yes No If No, describe

(b) Any changes or modification in equipment? Yes No If Yes, describe

(c) Evidence of lack of maintenance Yes No If Yes, describe

6.3 INSPECTION FOLLOW-UP PROCEDURES

After the completion of the inspection, the IO must determine the compliance status of the source. If an inspection indicates that a source is not operating in compliance with applicable regulations, the IO should follow the established Agency procedures regarding notice of violation, request for source test, and related matters.

The various items which could result in a determination of non-compliance would include:

- Emissions in excess of 30% opacity for over three minutes in any one hour[6]
- Emissions of carbon monoxide in excess of 0.056 percent by volume
- Emissions of particulate matter in excess of 1.0 kg per 1,000 kg of coke burnoff
- Monitoring equipment for opacity not being in operation
- Records of daily average coke burnoff rate and hours of operation for any fluid catalytic unit catalyst regenerator subject to NSPS not being kept

The IO checks to ensure that permits have been granted for all applicable processes and equipment and their modifications. For any later public complaints, he determines cause of complaint, records pertinent data, issues violation notices if appropriate, and ascertains adequacy of plans for prevention of future accidents. He periodically reviews emergency procedure plans. He makes sure that all shutdown procedures are being implemented during periods of process curtailment. He coordinates with other agencies participating in pollution reduction effort. As a part of inspection follow-up procedures, he also checks to see that engineering, procurement, installation, and testing of equipment is proceeding according to the approved plan.

[6] Appendix B demonstrates the proposed change to this regulation limit.

REFERENCES FOR CHAPTER 6

1. Weisburd, M.I., "Air Pollution Control Field Operations Manual, A Guide for Inspection and Enforcement," Department of Health, Education and Welfare, Public Health Service, Division of Air Pollution, Washington, D.C., Publication No. 937, 1962.

2. Brandt, C.S., and W.W. Heck, "Effects of Air Pollutants on Vegetation," in "Air Pollution," Vol. I, Stern, A.C. (Ed.), New York, Academic Press, 1968.

3. "Guide for Compiling a Comprehensive Emission Control Inventory (revised)," Environmental Protection Agency, Research Triangle Park, N.C., Publication No. APTD - 1135, March, 1973.

4. "Field Surveillance and Enforcement Guide for Petroleum Refineries (Final Draft)," prepared by The Ben Holt Co., Pasadena, California for Environmental Protection Agency, Research Triangle Park, N.C., July, 1973.

5. Federal Register, Vol. 41, No. 171, September 1, 1976.

7.0 PERFORMANCE TEST

The NSP Standards require a performance test of any new or modified Fluid Catalytic Cracking Regenerator. In order to guarantee the validity of the test, an inspection team will be present at the facility for observation. The ideal team consists of three enforcement personnel with the following areas of responsibility during the test period.

- Monitor process operating conditions from the control room
- Make visible observations of opacity and process operations from the plant area.
- Monitor emission testing procedures from the test site

Each team member should fill out check list type data during the test and submit a report including analysis of the data and indication of any upset conditions which may have affected the test.

7.1 PROCESS OPERATING CONDITIONS

For the purpose of obtaining source test data which is truly representative of the operating characteristics of the Catalyst Regeneration Unit being tested, it is extremely important that the test be conducted at or above the maximum production rate at which the particular unit will normally be operated. In certain cases, the EPA may feel that conditions other than the maximum production operating rate of the unit should be used to achieve valid test results. In such cases, the EPA will specify the conditions at which source testing must take place. In all cases, inspectors must personally verify that the unit is operating at the specified conditions and has stabilized at a steady state of operation. Such verification should be made with the unit operator and refinery manager, and inspectors should observe process controls (i.e., gauges, rate meters, and recorders) to determine that operating conditions are as specified. During the course of the source test, inspectors should periodically check operating conditions of the unit, carefully noting any changes in operating parameters such as temperature, pressure, fuel flow rate, or changes in the input and/or product process rate.

Since the standards apply at the point(s) where undiluted gases are discharged from the air pollution control system (or from the point of discharge from the unit, if no pollution control device is present), inspectors must make sure testing is done at correct locations. While the requirement to correct for dilution air during sampling was deleted from 40 CFR Section 60.106 (c), the IO should constantly be aware of signs of concealment due to dilution (circumvention). This

practice is a violation of 40 CFR Section 60.12: "No owner or operator subject to the provisions of this part (NSPS) shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere."

7.2 PROCESS OBSERVATIONS

The products of the Fluid Catalytic Cracking Unit are: gaseous hydrocarbons, gasoline, gas oil, and coke. The coke is adsorbed on the spent catalyst fines which are then rendered useless for further cracking until they are regenerated. Spent catalyst fines settle out of the cracking reactor and are drawn off at a controlled rate. They are then purged with steam, and transferred (by air stream) to the regenerator where the coke deposited on the catalyst fines is burned off. The normal decoking operation produces large amount of carbon monoxide (CO) which is routed by means of ducting to a "CO Boiler" which burns the carbon monoxide (CO) to carbon dioxide (CO_2) utilizing the resultant heat of combustion to produce steam for other refinery processes (auxiliary fuel is used to aid the combustion of CO to CO_2). The particulate material carried over consists of suspended catalyst fines which are recovered by the emission control equipment. This equipment should consist of a series of centrifugal collectors (cyclones) and an electrostatic precipitator.

At the time the performance test is conducted, the inspector should make careful notation as to the existing layout of the process unit, operating range parameters of the unit, and the type of pollution control equipment with which the unit is equipped. The control equipment is especially important since subsequent source performance testing will be affected by any modifications in this equipment. Inspectors should note the number, size, and order of centrifugal collectors (cyclones), as well as the model and maximum efficient operating rate and the number of parallel trains of the electrostatic precipitator. If possible, a photographic record should be obtained of control equipment installations for future record. Specific note should also be made as to provisions for disposal of carbon monoxide from the catalyst decoking operation. Inspectors should determine that this gas is transported to a "CO Boiler" and what provisions exist for accurately measuring the feed of CO from the regeneration unit to the CO boiler.

The equipment check list is the same as that which is suggested in Section 6.2.

7.3 EMISSION TEST OBSERVATIONS

Emission source testing discussed here concerns determining compliance of new sources with EPA New Source Performance Standards. During the source testing operations, field inspectors should periodically spot check testing procedures, equipment, and data to make certain that the test being conducted is valid.

All performance tests should be conducted while the unit being tested is operating at or above maximum production rate at which the unit will normally be operated. If the EPA Administrator feels that other conditions should be used to achieve valid test results, such conditions must be used as basis for testing.

The official EPA testing procedures are periodically improved. In order to familiarize the IO with the most current methods, a brief description of the various applicable official EPA methods is presented.

7.3.1 Traversing (EPA Method No. 1)

Of first importance is the selection of a sampling point and determination of the minimum number of traverse points to ensure the collection of a representative sample. Inspectors should check to determine if the sampling site selected is a minimum of two (2) diameters downstream and at least one-half (1/2) diameters upstream from any disturbance to the flow of gases within the duct or stack which is being sampled. Such disturbances are commonly caused by expansions or contractions, bends, visible flames, observable cross members, or other entering ducts.

For certain processes, this may prove impossible to meet. In that case, the IO will determine the sampling point based upon the equation presented in the official EPA methods appearing in the Federal Register, Volume 39, No. 47, - Friday March 8, 1974.

7.3.2 Stack or Duct Gas Velocity Determination (EPA Method No. 2)

In the determination of gas velocity within the duct or stack, the inspector should be certain that all data from each traverse point is carefully and accurately recorded, as this is the basic information used to determine the isokinetic sampling rate. Each point shall be identified by a number and the following information shall be recorded for each point: velocity head in mm (or inches) of water, stack (duct) pressure in mm (or inches) of mercury, and temperature. Care should be taken to determine that a type "S" pitot tube or equivalent is used to obtain the velocity head readings and that this tube is of sufficient length to reach all traverse points. The pitot tube should be graduated with temporary markings (i.e., tape or indelible ink, etc.) such that

each traverse point may be reached by successively moving the tube deeper into or withdrawing it further from the duct or stack being sampled. All tubing and connectors between the pitot tube and the inclined manometer or draft gauge should be tight and leak-free. An inclined manometer or draft gauge should be used to obtain velocity head readings from the pitot tube. Make certain that this gauge is filled with sufficient colored liquid to give readings throughout its range of calibration, and that the manometer liquid level is adjusted to read "zero" with the end of the pitot tube shielded from incidental breezes prior to beginning the velocity head measurment. Periodically check to make sure that no constriction occurs in the hose connections during the course of the velocity head measurement.

The most common means of stack temperature measurement is by thermocouple and potentiometer; operation of this equipment is rather straight-forward although several points should be checked to ensure accurate measurement. The thermocouple connecting wires should be securely tightened to the terminal lugs on the potentiometer, and it should be determined that the thermocouple circuit is complete (an open circuit will be evident if the potentiometer fails to balance, giving readings off the scale of the instrument). If the potentiometer being used is not an automatic compensating type (automatic reference to ambient temperature), see that the ambient air temperature has been recorded or that the potentiometer scale has been calibrated with this temperature as a reference. While taking gas temperature readings, sufficient time should be allowed (normally about five minutes) for the thermocouple probe to reach thermal equilibrium with the duct gas before taking the first few readings.

As part of the data necessary for the velocity determination, the static pressure within the stack or duct should be measured. If a "S"type pitot tube is used, the static pressure in the stack can be determined by rotating the pitot tube onto its side. This can also be done using a mercury filled "U" tube manometer, one end of which is open to the atmosphere and the other connected to a probe extending into the duct or stack itself. Again, the tubing from the probe to the manometer must be free of constrictions and tightly connected at both ends. A barometric pressure reading (of atmospheric pressure) in inches of mercury, should be obtained from a standard barometer located in the general vicinity of the test site; this can be a wall mounted barometer in the plant offices, laboratory, or any convenient location which is at ambient temperature and free of vibration.

If such a device is not available, barometric measurements in the general vicinity of the test site can also be obtained by calling the local weather station and asking for the station pressure and correcting for test conditions (i.e. altitude).

7.3.3 Gas Analysis (EPA Method No. 3)

Two methods of sampling are acceptable in obtaining an analysis of the gases within a duct or stack; grab sampling and integrated sampling. In the grab sampling method, the gases are drawn through a probe directly into an Orsat type analyzer. If grab sampling is used, inspectors should make sure that the sampling probe is of pyrex or stainless steel (316) construction and that a small piece of glass wool has been loosely inserted in the end of the probe to stop particles. A flexible tubing is used to connect the probe with the analyzer, however, there must be some provision for purging the line; most often a one-way squeeze bulb is used. During analysis using the Orsat, notice that care is being taken to equalize the liquid levels with the leveling bottle when readings are taken, and that the efficiencies of the absorbing solutions are such that no more than ten (10) passes are required to achieve constant readings (usually three to five passes will produce a constant reading).

The integrated sampling method utilizes the same type of probe, but requires an air-condenser to remove moisture, as well as a valve, pump, and rotameter in line between the probe and sample. If the velocity of the gas varies with time or if a "sample traverse" is taken, a type "S" pitot tube may be used along with the probe so that the sampling rate can be kept proportional to the gas velocity. The rotameter should have a flow range from 0 to 0.001 cubic meters/min. In operation, the sampling line is purged using the pump and the pre-evacuated flexible sample bag is attached to the system via a quick disconnect coupling. Sampling is carried out at a rate proportional to the gas velocity using the rotameter as a guide and the valve for control. The sample bag should be large enough to obtain a sample of about 0.232 to 0.708 cubic meters. Again, all connections must be leak-free. After sampling is complete, the bag is transferred to an Orsat apparatus for analysis. Gas analysis must be performed whenever a determination of particulate matter (Method 5), sulfur dioxide (Method 6), or carbon monoxide (Method 10) is carried out.

7.3.4 Moisture (EPA Method No. 4)

The moisture content of the duct or stack gas is obtained by extracting a sample at isokinetic rate and collecting the condensate in midget impingers. The moisture determination is carried out at the same site used to determine the volumetric flow rate. Sampling time must be at least 60 minutes with the minimum final collected volume being 0.6 M^3 (20 ft^3) at standard conditions. Select the sampling site and minimum number of sampling points according to EPA Method 1.

The items to be spot checked by inspectors during moisture sampling are the same observed during particulate matter testing with the following differences:

The impingers in this case are of the "midget" variety (30 ml capacity) and should contain about 5 ml of distilled water each. Since condensate silicon gel is determined on a weight basis, make certain that it has been tared prior to their placement in the ice-water bath. As before, determine that initial temperature, volume, and barometric pressure have been properly recorded. Check probe heater operation (120°C at impinger end) and all connections for tight seals. A silica gel drying tube should be placed in the line directly behind the impingers.

The following data should be recorded for the purpose of checking calculations later: sampling time, gas volume through meter, rotameter setting, and the temperature of the meter throughout the testing period.

7.3.5 Particulate Matter (EPA Method No. 5)

When sampling for particulate matter according to EPA Method 5, the minimum sampling rate will be 0.014 M^3 per minute and the sampling period will be at least 2 minutes per point. During the sampling operation, the inspector should check the probe liner to make sure it is either pyrex or [illegible] glass. When length limitations are encountered stainless steel [illegible]) or Incoloy 825 may be used. The probe nozzle will be a stainless steel (316) nozzle with a sharp, tapered leading edge. The use of stainless steel ensures non-reactivity of the probe material with either the gas stream or the sample being collected. These materials are selected also because of their resistance to distortion at elevated temperature. The probe nozzle must be pointed opposed to the direction of gas flow while the sample is being collected, and a type "S" pitot tube be attached with a 1.9 cm (3/4 inch) separation between it and the nozzle in order to monitor the gas velocity. Check to determine that the probe heater is working (about 120°C at the probe outlet), and that a fresh filter was placed in the filter holder before beginning the test. The filter-heating system must also be operating.

The impinger box must be filled with an ice and water bath and there should be an additional supply of ice on hand to maintain the bath cold enough so that the impinger temperature remains at 20°C or less throughout the test. Four Greenburg-Smith type impingers are placed in series in the ice bath and connected by means of ball and socket joints. All glassware should be clean and the ball joints should be snugly connected and secured with the proper size metal spring clamp.

Note that the second impinger in the series has the conventional impingement nozzle, but that all others have the straight glass tubing extending to 1/2 inch from the bottom. The first two impingers in the series have exactly 100 ml of water each (measured by graduated cylinder), the third is empty, and the fourth must contain 200 grams (preweighted) of silica gel, preferable the indicating type.

A thermometer should be placed in or just after the fourth impinger, followed by a check valve to prevent reverse-flow surges. From this point the line should contain the following components: vacuum gauge, main valve, air tight pump with bypass valve, dry gas meter with temperature dials at inlet and outlet, and an orifice meter connected to an inclined manometer, respectively.

Check to make sure that all gauges and temperature dials are operating properly, and that all appropriate valves are in open position (bypass will normally remain closed), that pump and test meter are correctly functioning, and be sure than connecting lines are attached to their proper inlets and outlets - reverse order is a common mistake here. Both pitot and orifice manometers should be checked out as previously described.

The following information should be recorded from the data sheets for the purpose of spot-checking the accuracy of the calculated final results.

(a) Average velocity, head, mm H_2O

(b) Average gas temperature, ^{o}C

(c) Static pressure in duct or stack, mm Hg

(d) Barometric pressure, mm hg

(e) Diameter of duct or stack

(f) Sampling time (start to finish)

(g) Average pressure differential across orifice meter

(h) Gas sample volume

(i) Gas sample temperature at dry gas meter (average for inlet and for outlet)

(j) Impinger bath temperature, ^{o}C

(k) Impinger temperature, ^{o}C

(l) Volume of condensate collected in impingers, ml

7.3.6 Carbon Monoxide (EPA Method No. 10)

The sampling train should consist of the following: A stainless steel or pyrex (sheathed) probe equipped with a particulate filter, an air condenser to remove excess moisture, a needle valve and flow rate meter (rotameter), and finally a quick disconnect coupling. A pump and flexible bags (60-90 liters) must be on hand or, bags can be pre-evacuated in the laboratory.

Not less than 60 minutes shall be consumed in sampling. A type "S" pitot tube should be used along with the sampling probe in order to monitor the gas velocity and keep the rate of sampling proportional to the gas velocity. Since analysis is accomplished by instrumental means based on comparison of sample to prepared standards, collection of field data for checking results is not applicable here. If analysis is at or near the sampling location, check to make sure the NDIR analyzer has an operating range of at least 0 - 1,000 ppm and several scales of various sensitivities.

The line to the analyzer will then also have a quick-disconnect coupling followed by a pump, needle valve, flow rate meter, two traps in series (one containing "indicating" type of silica gel; the other containing "Ascarite" or equivalent), and provisions for introduction of calibrating gas. The calibrating gas will include a "zero gas" and a "span gas" (standard concentration of CO); these gases can be introduced to the sampling line via a branch "T" pipe with provisions for metering the rate of introduction of the calibration gases. The nondispersive infrared analyzer (NDIR) is the last step in the sampling analysis line.

7.3.7 Emission Monitoring

Since continuous emission source monitoring is required for opacity of particulate materials, inspection must be made of monitoring instruments to determine that they are properly installed and operating, and that proper calibration and maintenance procedures are being followed.

For particulate emission monitoring the photoelectric monitor may be used. This essentially measures the opacity or optical density of a stream of gases. Characteristically such installations are in widespread use and operate on the principle that particulate matter, in a gas stream, will interrupt a beam of light (between source and detector) in proportion to its concentration in the gas stream. In practice the system consists of a light source, a detector (photomultiplier tube), and a recorder. Often an alarm feature is incorporated in the system to sound when the opacity reaches a predetermined level. These systems work well if maintenance and calibration are performed on

a regular and thorough basis. It should be determined that: calibration is frequently performed, optical surfaces are kept clean and in proper repair, proper alignment of source and detector is maintained, and that recorder and alarm systems are in good working order. Variations exist between many different suppliers of such opacity metering systems, however, the principle involved as well as the operating problems are basically alike for these systems in general.

Some systems may have both the source and detector on the same side of the stack, utilizing reflectance to return the light beam. Calibration and zeroing is quite a problem while the plant is operating; one technique often employed uses a sliding tube to connect the source and detector and thus exclude the gas stream from the beam path for calibration.

Source monitoring installations should be free from vibration, shock, and excessive heat, should be weathertight and so placed as to provide safe and convenient access for calibration purposes.

The Inspection Officer should be careful to ascertain from the operators the frequency of calibration and the calibration techniques used. Calibration frequencies of less than once every two or three days are not desirable.

REFERENCES FOR CHAPTER 9

1. Federal Register, Vol. 36, December 23, 1971.
2. Federal Register, Vol. 38, No. 1111, June 11, 1973.
3. "Field Surveillance and Enforcement Guide for Petroleum Refineries (Final Draft)," prepared by The Ben Holt Co., Pasadena, California for Environmental Protection Agency, Research Triangle Park, N.C., July, 1973.
4. Federal Register, Vol. 41, No. 111, June 8, 1976.

APPENDIX I

NEW SOURCE PERFORMANCE STANDARDS FOR FLUID CATALYTIC CRACKING REGENERATORS

Reproduced from best available copy.

Subpart J—Standards of Performance for Petroleum Refineries

§ 60.100 Applicability and designation of affected facilities.

The provisions of this subpart are applicable to fluid catalytic cracking unit catalyst regenerators, fluid coking unit combustion devices, and fuel gas combustion devices (except as provided in paragraph (b) of this section) which are located at petroleum refineries and for which construction, modification, or reconstruction is commenced after June 11, 1973.

§ 60.101 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

"Fluid catalytic cracking unit catalyst regenerator" means any device used to regenerate coke-contaminated catalyst from a fluid catalytic cracking unit by burning off the coke deposits.

"Fluid coking unit combustion device" means any equipment, such as process heaters, boilers, or flares used to combust fluid coking unit exhaust gases, but does not include any facility primarily used for steam generation.

"Fuel gas combustion device" means any equipment, such as process heaters, boilers, and flares used to combust fuel gases, but does not include any facility primarily used for steam generation.

"Petroleum refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricating oils, or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

"Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

"Process heater" means a device, primarily used in petroleum refining processes, which transfers heat released by combusting fuel gases to process streams or to heat transfer liquid other than water.

"Reconstruction" means the replacement of components of an existing facility to such an extent that (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible for the facility to meet the applicable standards set forth in this subpart. Individual decisions on specific facilities will be determined by the Administrator on a case-by-case basis according to the provisions set forth in § 60.15.

"Refinery process unit" means any segment of the petroleum refinery in which a specific processing operation is conducted.

"Refinery fuel gas combustion device" means any equipment, such as process heaters, boilers, and flares used to combust fuel gases, but does not include any facility primarily used for steam generation.

"Refinery fuel gas" means any fuel gas combusted in a petroleum refinery process unit, except fuel gas produced during coking operations and fuel gas produced during catalytic cracking unit catalyst regeneration.

"Fuel gas" means any gas which is generated by a petroleum refinery process unit or any gaseous mixture of natural gas and fuel gas.

"Natural gas" means the gas which is produced by a petroleum refinery process unit and is composed primarily of methane and ethane and is commonly known as natural gas.

"Flare" means a thermal oxidation device using an uncontrolled flame at the outlet of a stack.

"Process upset gas" means any gas generated by a petroleum refinery process unit as a result of start-up, shutdown, upset, or malfunction.

"Fuel gas combustion device" means any equipment, such as process heaters, boilers, and flares used to combust fuel gases, but does not include any fluid catalytic cracking unit catalyst regenerator, fluid coking unit combustion device, or any facility primarily used for steam generation.

"Coke burn-off" means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.106.

§ 60.102 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator particulate matter in excess of 1.0 kg per 1000 kg (1.0 lb per 1000 lb) of coke burned.

(b) Flares exhibiting an opacure greater than 30 percent, except for 5 minutes in any 1 hour, is

(b) In those instances in which sulfur-bearing liquid or solid fossil fuels are burned in the fluid catalytic cracking unit incinerator-waste heat boiler, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate emissions shall not exceed 0.18 g/million cal (0.18 lb/million Btu) of heat input attributable to such liquid or solid fuel.

§ 60.103 Standard for carbon monoxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from the fluid catalytic cracking unit catalyst regenerator any gases which contain carbon monoxide in excess of 0.050 percent by volume.

§ 60.104 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall burn in any fuel gas combustion device any fuel gas which contains H₂S in excess of 230 mg/dscm (0.10 gr/dscf), except as provided in paragraphs (b) and (c) of this section. The combustion of process upset gas or a fuel gas which is released to the flare as a result of relief valve leakage is exempt from this paragraph.

(b) The owner or operator may elect to treat fuel gas resulting from the combustion of fuel gas in a manner which limits the release of SO₂ to the atmosphere as if it is shown to the satisfaction of the Administrator that this prevents SO₂ emissions as effectively as compliance with the requirements of paragraph (a) of this section.

§ 60.105 Emission monitoring.[1]

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator as follows:

(1) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the fluid catalytic cracking unit catalyst regenerator. The continuous monitoring system shall be operated at all times except during periods of start-up, shutdown, or malfunction.

(2) [Reserved]

(3) A continuous monitoring system for the measurement of sulfur dioxide in the gases discharged into the atmosphere from the combustion of fuel gases resulting from the emissions monitoring system for the measurement of sulfur dioxide in fuel gases combusted in fuel gas combustion devices except where natural gas is the only fuel combusted. The continuous monitoring system shall be located downstream of any control equipment.

(b) For the purpose of reports under § 60.7(c), any excess emissions that ought to be reported are defined as follows:

(1) [Illegible]

(2) [Illegible]

(3) [Illegible]

(4) [Illegible]

(c) Any 24-hour period during which the average [illegible] is more than six times the applicable standard established in § 60.102 or § 60.104 shall be considered a violation of the applicable standard for the purpose of § 60.7(d).

§ 60.106 Test methods and procedures.

(a) For the purpose of determining compliance with § 60.102(a)(1), the following reference methods and calculation procedure shall be used:

(1) For concentration of particulate matter and velocity traverses, Method 5.

(2) For velocity and volumetric flow rate, Method 2.

(3) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/hr (0.53 dscf/hr). Isokinetic sampling shall be used. Acetone shall not be used in the cleanup of glassware or sampling equipment prior to particulate matter determination.

(4) Particulate matter in excess of that permitted in § 60.102(a)(1) shall be calculated as the product of the particulate matter concentration as determined by Method 5 and the volumetric flow rate as determined by Method 2.

(5) Coke burn-off rate shall be determined by [illegible] formula:

[illegible]

[illegible]

For the [illegible] coke burn-off rate [illegible] concentration of carbon dioxide, carbon monoxide, and organic compounds which is subject to § 60.102 a sample volume is taken over a period of time sufficient to represent the exhaust gas flow from the fluid catalytic cracking unit catalyst regenerator. The owner or operator shall record data on the following parameters and use the values in the equation below which yield a solid fossil fuel burn-off rate of zero:

(i) [Illegible]

(ii) [Illegible]

(iii) [Illegible]

(iv) [Illegible]

(v) [Illegible]

(vi) [Illegible]

(b) Any 24-hour period during which the average [illegible] is more than six times the applicable standard established in § 60.102 or § 60.104 shall be considered a violation of the applicable standard for the purpose of § 60.7(d). Any 24-hour period during which the average [illegible] is more than the standard under § 60.104

§ 60.107 Test methods and procedures.

(a) For the purpose of determining compliance with § 60.104(a)(1), the following reference methods and calculation procedure shall be used:

(1) For concentrations of SO₂ and O₂ in the stack gases, Method 6 for the concentration of particulate matter and Orsat analysis for O₂.

(2) Method 1 for sample and velocity traverses.

(3) Method 2 for velocity and volumetric flow rate.

(4) For Method 6, the sampling time for each run shall be at least 30 minutes and the gas flow rate should be at least 0.14 dscm/hr (5 dscf/hr). Acetone shall not be used in the cleanup of glassware or sampling equipment prior to particulate matter determination.

(5) Sulfur dioxide from the fluid catalytic cracking unit catalyst regenerator for the purpose of [illegible] shall be determined by [illegible] Method 6 for the concentration of SO₂ and particulate matter, respectively, Method 1 for sample traverses, and Method 2 for velocity and volumetric flow rate.

(6) Sulfur burn-off rate shall be determined by [illegible] formula:

[illegible]

(b) Particulate emissions shall be determined by the following equation:

[illegible]

(c) For each run, emissions expressed in kg/1000 m^3 (English units) [illegible] of coke burn-off in the catalyst regenerator shall be determined by the following equation:

[illegible]

(d) In those instances in which auxiliary liquid or solid fossil fuels are burned in an incinerator-waste heat boiler, the rate of particulate matter emissions permitted under § 60.12(b) shall be determined. Auxiliary fuel heat input, expressed in millions of cal/hr (million Btu/hr), shall be calculated for each run by fuel flow rate measurement and analysis of the fuels to which auxiliary fuels are burned. For each run, the rate of particulate emissions permitted under § 60.12(b) shall be calculated from the following equation:

[illegible]

(e) Method 8 shall be used for determining concentration of SO_2 to determine compliance with § 60.104(b), except that the concentration of the fuel gas may be determined instead. Method 1 shall be used for velocity traverses and sampling of the determining velocity and volumetric flow rate. The sampling site for determining SO_2 concentration by Method 8 shall be the same as for determining volumetric flow rate. The sampling point for determining SO_2 concentration by Method 8 shall be at the centroid of the cross section if the cross sectional area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 inches) if the cross sectional area is 5 m^2 or more and the centroid is more than one meter from the wall. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples shall constitute one run. Samples shall be taken at approximately 1-hour intervals. For short fuel gas runs, samples totaling less than 10 minutes may result in depletion of the collecting solution, although fuel gases containing low concentrations of hydrogen sulfide may necessitate sampling for longer periods of time.

(f) Method 8 shall be used for determining concentration of SO_2 to determine compliance with § 60.104(b), except that the concentration of the fuel gas may be determined instead. Method 1 shall be used for velocity traverses and sampling of the determining velocity and volumetric flow rate. The sampling site for determining SO_2 concentration by Method 8 shall be the same as for determining volumetric flow rate. The sampling point for determining SO_2 concentration by Method 8 shall be at the centroid of the cross section if the cross sectional area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 inches) if the cross sectional area is 5 m^2 or more and the centroid is more than one meter from the wall. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples shall constitute one run. Samples shall be taken at approximately 1-hour intervals.

(g) For the purpose of determining compliance with § 60.104(b), the integrated sample technique of Method 10 shall be used. The sample shall be extracted at a rate proportional to the gas velocity at a sampling point near the centroid of the fuel gas line. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples shall constitute one run. Samples shall be taken at approximately 1-hour intervals. For short fuel gas runs, sample time exceeding 30 minutes may result in depletion of the collecting solution, although fuel gases containing low concentrations of hydrogen sulfide may necessitate sampling for longer periods of time.

(h) For the purpose of determining compliance with § 60.104(b), Method 11 shall be used, which is theory if gas lines are operating at pressures substantially above atmospheric, the gases sampled must be introduced into the sampling train at approximately atmospheric pressure. This may be accomplished with a flow control valve if the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples shall constitute one run. Samples shall be taken at approximately 1-hour intervals. For short fuel gas runs, sample time exceeding 30 minutes may result in depletion of the collecting solution, although fuel gases containing low concentrations of hydrogen sulfide may necessitate sampling for longer periods of time.

[illegible]

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids

§ 60.110 Applicability and designation of affected facility.

(a) Except as provided in § 60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,416 liters (40,000 gallons).

(b) This subpart does not apply to storage vessels for the crude petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

§ 60.111 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Storage vessel" means any tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 15 pounds per square inch gauge without emissions to the atmosphere except under emergency conditions.

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) "Petroleum liquids" means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Number 2 through Number 6 fuel oils as specified in A.S.T.M. Specification D396-69, gas turbine fuel oils Numbers 2-GT through 4-GT as specified in A.S.T.M. Specification D2880-71, or diesel fuel oils Numbers 2-D and 4-D as specified in A.S.T.M. Specification D975-68.

(c) "Petroleum refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

(d) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(e) "Hydrocarbon" means any organic compound consisting predominantly of carbon and hydrogen.

(f) "Condensate" means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature and/or pressure and remains liquid at standard conditions.

(g) "Custody transfer" means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

(h) "Drilling and production facility" means all drilling and servicing equipment, wells, flow lines, separators, equipment, gathering lines, and auxiliary nontransportation-related equipment used in the production of petroleum but does not include natural gasoline plants.

(i) "True vapor pressure" means the equilibrium partial pressure exerted by a petroleum liquid as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from Floating Roof Tanks, 1962.

(j) "Floating roof" means a storage vessel cover consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the petroleum liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and tank wall.

(k) "Vapor recovery system" means a vapor gathering system capable of collecting all hydrocarbon vapors and gases discharged from the storage vessel and a vapor disposal system capable of processing such hydrocarbon vapors and gases so as to prevent their emission to the atmosphere.

(l) "Reid vapor pressure" is the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids, except liquified petroleum gases, as determined by ASTM D323-72 (reapproved 1982).

§ 60.112 Standard for hydrocarbons.

(a) The owner or operator of any storage vessel to which this subpart applies shall store petroleum liquids as follows:

(1) If the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), this storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

(2) If the true vapor pressure of the petroleum liquid as stored is greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a vapor recovery system or its equivalent.

§ 60.113 Monitoring of operations.

(a) The owner or operator of any storage vessel to which this subpart applies shall for each such storage vessel maintain a file of each type of petroleum liquid stored, of the typical Reid vapor pressure of each type of petroleum liquid stored, and of the dates of storage. The file on which the storage vessel is empty shall be [illegible].

(b) The owner or operator of any storage vessel to which this subpart applies shall for each such storage vessel determine and record the average monthly storage temperature and true vapor pressure of the petroleum liquid stored at such temperature if:

(1) The petroleum liquid has a true vapor pressure, as stored, greater than 69 mm Hg (1.5 psia) but less than 76 mm Hg (11.1 psia) and is stored in a storage vessel other than one equipped with a floating roof, a vapor recovery system or their equivalents; or

(2) The petroleum liquid has a true vapor pressure, as stored, greater than 570 mm Hg (11.1 psia) and is stored in a storage vessel other than one equipped with a vapor recovery system or its equivalent.

(c) The average monthly storage temperature is an arithmetic average calculated for each calendar month from daily readings. If storage is for less than a month, only daily readings are averaged. The true vapor pressure is determined by [illegible] every 6 days.

(d) The true vapor pressure shall be determined by the procedures in API Bulletin 2517. This procedure is dependent upon determining the average storage temperature and the Reid vapor pressure, which requires sampling of the petroleum liquids in the storage vessel. Unless the Administrator requires specific cases that the stored petroleum liquid be sampled, the true vapor pressure may be determined by using the average monthly storage temperature and the typical Reid vapor pressure for those liquids for which certified specifications limiting the Reid vapor pressure exist. Reid vapor pressure may be used for other liquids, supporting data must be made available to the Administrator when typical Reid vapor pressure is used.

APPENDIX A

PROPOSED REVISION TO THE OPACITY STANDARD FOR NEW FLUID CATALYTIC CRACKING REGENERATORS

Reproduced from best available copy.

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 604-4]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators

Under the authority of section 111 of the Clean Air Act, as amended, this Administrator is proposing a revision to [illegible] and [illegible] opacity standard of performance for new, modified, and reconstructed petroleum refinery fluid catalytic cracking unit catalyst regenerators.

Previous Revision

The proposed revision would change the opacity standard from 30 percent, except for three minutes in any one hour, to 30 percent, except for two six-minute average opacity readings in any one hour. The revised standard would be neither more nor less stringent than the present standard, but would be consistent with the new procedure for determining the opacity of emissions.

Rationale

On June 22, 1973, the U.S. Court of Appeals for the District of Columbia circuit remanded to EPA the new source performance standard for particulate emissions (40 CFR 60.82) promulgated under section 111 of the Clean Air Act (Portland Cement Association v. Ruckelshaus, 486 F. 2d 375). One of the issues remanded was the use of opacity standards. On November 15, 1973, EPA proposed to the contrary (38 FR 30977), and on May 22, 1974, the Court approved the use of opacity standards (158 F. 2d 911).

In the response, EPA reconsidered the use of opacity standards, and concluded that they are a reliable, inexpensive, and useful means of ensuring that control equipment is properly maintained and operated at all times. EPA also made changes to the general provisions of 40 CFR Part 60 and to the test method for determining the opacity of emissions to eliminate the possibility of a properly maintained and operated source being in violation of the applicable opacity standard while concurrently meeting the mass concentration emission standard applicable to the source.

The principal revisions to the regulations (40 CFR Part 60, Standards of Performance for New Stationary Sources) which apply to all opacity standards are as follows:

1. Reference Method 9 (the opacity test method) was revised to [illegible] on the average of 24 consecutive opacity readings taken [illegible] from [illegible] to [illegible] minutes. [illegible] the opacity standard [illegible] the average of any six-minute period during the hour. [illegible] the opacity standard [illegible] the average of any two six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any three six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any four six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any five six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any six six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any seven six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any eight six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any nine six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any ten six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any eleven six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any twelve six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any thirteen six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any fourteen six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any fifteen six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any sixteen six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any seventeen six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any eighteen six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any nineteen six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any twenty six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any twenty-one six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any twenty-two six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any twenty-three six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any twenty-four six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any twenty-five six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any twenty-six six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any twenty-seven six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any twenty-eight six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any twenty-nine six-minute periods during the hour. [illegible] the opacity standard [illegible] the average of any thirty six-minute periods during the hour.

2. Section 60.11(c) was added to provide a [illegible] for [illegible] to perform the [illegible] tested to enable a [illegible] standard [illegible] of records that [illegible] have kept the records [illegible] to enable [illegible] to [illegible] the opacity standard. [illegible] the [illegible] [illegible] [illegible]

[illegible] barrels per day are built or reconstructed, and these facilities have to be designed and [illegible] to meet the standards [illegible] under section 111 of the Act.

All fluid catalytic cracking units, coking units, fluid coking units, and thermofluid coking units are [illegible] to certain existing boilers [illegible] Generally, the boiler units require fuel switching to lower sulfur fuels because of the high [illegible] costs involved in [illegible] the gases from the catalyst regenerator. Additionally, although [illegible] temporarily, it [illegible] the level of the newly promulgated [illegible] that an extension of the existing [illegible] would [illegible] to permit coal burning. Thus, an [illegible] was [illegible] and used in the proposed revision to the opacity standard.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect emission limits [illegible] with the best [illegible] demonstrated systems of emission reduction considering the cost of [illegible] Emission [illegible] (RACT) required to be implemented under section 110 of the Act, on the other hand, must [illegible] for the attainment and maintenance of [illegible] standards (NAAQS) designed to protect public health and welfare. For that purpose, [illegible] must in some cases require greater [illegible] than those required by standards of performance for new sources. In addition, States are free under section 116 of the Act to establish more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS. Consequently, new or modified sources may in some cases be required to [illegible] more stringent limits than EPA's standards of performance under section 111.

Public Participation

Interested persons may participate in this proposed revision by submitting written comments to the Administrator (see [illegible]). Comments should be submitted to the Director, Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Mr. Don R. Goodwin. The Administrator will welcome comments on all aspects of the proposed revision.

All relevant comments received on or before October 20, 1976 will be considered. Comments received will be available for public inspection and copying at the EPA Public Information Reference Unit, Room 2922 (EPA Library), 401 M Street, S.W., Washington, D.C.

Background information on this proposed revision of the opacity standard for petroleum refinery fluid catalytic cracking unit catalyst regenerators has been published in a document "Revision of Opacity Standards for Particulate Emissions from Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators." Copies of this document may be obtained by writing to the Public Information Center (Pm-213), U.S. Environmental Protection Agency, Washington, D.C. 20460. Copies of "Determination of Opacity Standards of Particulates: Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators."

Appendix

The notice of proposed rulemaking is issued under authority of sections 111, 114, and [illegible] of the Clean Air Act, as amended by [illegible] 1977 [illegible] of Title 40 of the Code of Federal Regulations is [illegible]:

Dated: August 20, 1976.

Douglas M. Costle,
Administrator.

It is proposed to amend Part 60 of Chapter I, [illegible] of the Code of Federal Regulations as follows:

1. Section 60.102(a)(1) is revised to read as follows:

§ 60.102 Standard for particulate matter.

(a) * * *

(1) Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour, where the presence of uncombined water is the only reason for failure to meet the requirements of this paragraph, such failure shall not be a violation of this section.

* * * * *

2. Section 60.105(a)(11) is revised to read as follows:

§ 60.104 Emission monitoring.

* * * * *

(a) * * *

(11) Opacity. All hourly records in which there are three or more six-minute average opacity readings during which the average opacity of the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator subject to § 60.102 exceeds 30 percent.

* * * * *

[FR Doc. 76-25000 Filed 8-27-76; 8:45 am]

APPENDIX B

ESTIMATION OF THE EXIT GAS VOLUME LEAVING THE FLUID CATALYTIC CRACKING UNIT REGENERATOR

In order for the Inspection Officer or other members of an enforcement agency to determine the compliance of a FCC regenerator with NSPS, it is necessary to use the coke burnoff equation discussed in the text. The problem is that after checking with many refineries, it was discovered that a continuous readout of the exit gas volume (Q_{RE}) is not available. The problem then becomes: how can this parameter be derived in order to use the equation?

One quantity which is on a continuous readout in the control room is the amount of air entering the regenerator on a dry basis (Q_{RA}). This gas is assumed to consist of 79% nitrogen and 21% oxygen. Since nitrogen is neither produced or destroyed in the regenerator, the only exit source for the nitrogen is through the top of the regenerator vessel. The nitrogen leaves as either nitrogen gas (N_2) or a nitrogen oxide (NO_x). The amount of the exit gas volume leaving as NO_x is approximately 200 ppm (from source test data) or 0.02% which is considered to be negligible. Therefore basically all of the nitrogen leaves as N_2. If the amounts of hydrocarbons, aldehydes, ammonia, and other trace elements are also considered to be on a negligible scale with respect to the exit gas volume, then the only exit gases on a dry basis will be CO, CO_2, O_2 and N_2.

$$\%N_2 + \%CO_2 + \%CO + \%O_2 = 100\% \text{ of exit gas volume}$$

$$\%N_2 = 100\% - (\%CO_2 + \%CO + \%O_2)$$

If the amount of nitrogen leaving is equal to the amount entering the regenerator:

$.79\ Q_{RA} = (\%N_2)\ (Q_{RE})$ where Q_{RE} is the exit gas volume on a dry basis

$$\frac{.79\ Q_{RA}}{\%N_2} = Q_{RE}$$

$$\frac{.79 Q_{RA}}{100\% - \%CO_2 - \%CO - \%O_2} = Q_{RE}$$